ATTACHMENT C: TESTING AND MONITORING PLAN 40 CFR 146.90

CLEAN ENERGY SYSTEMS MENDOTA

1. Facility Information

Facility name:	CLEAN ENERGY SYSTEMS MENDOTA MENDOTA_INJ_1
Facility contact:	Rebecca Hollis 400 Guillan Park Drive , Mendota, CA 93640 Office: 916-638-7967
Well location:	MENDOTA, FRESNO COUNTY, CA T13S R15E S32 LAT/LONG COORDINATES (36.75585015/-120.36440423)

This Testing and Monitoring Plan describes how Clean Energy Systems will monitor the Clean Energy Systems Mendota site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage zone to support AoR reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan (Schlumberger, 2021f).

This attachment is one of the several documents listed below that was prepared by Schlumberger and delivered to Clean Energy Systems. These documents were prepared to support the Clean Energy Systems preconstruction application to the EPA.

- Attachment A: Summary of Requirements Class VI Operating and Reporting Conditions (Schlumberger, 2021a)
- Attachment B: Area of Review and Corrective Action Plan (Schlumberger, 2021b)
- Attachment C: Testing and Monitoring Plan (Schlumberger, 2021c)
- Attachment D: Injection Well Plugging Plan (Schlumberger, 2021d)
- Attachment E: Post-Injection Site Care and Site Closure Plan (Schlumberger, 2021e)
- Attachment F: Emergency and Remedial Response (Schlumberger, 2021f)
- Attachment G: Construction Details (Schlumberger, 2021g)
- Attachment H: Financial Assurance Demonstration (Schlumberger, 2021h)
- Class VI Permit Application Narrative 40 CFR 146.82(A) Clean Energy Systems Mendota (Schlumberger, 2021i)
- Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j)

Contents

List of Figures

List of Tables

1.1 Abbreviations

AoR: Area of review
API: American Petroleum Institute
CalGEM: California Geologic Energy Management Division
CCS: Carbon capture and storage
CES: Clean Energy Systems
DAS: distributed acoustic sensing
DOGGR: Division of Oil, Gas, and Geothermal Resources (as of 2020, CalGEM)
DTS: distributed temperature sensing
EPA: Environmental Protection Agency
FNXS: fast neutron elastic scattering cross-section
GSH: gas-sigma-hydrogen index
GRAT: capture background corrected burst gamma ray count rate
ICP: inductively coupled plasma
KB: kelly bushing
MD: measured depth
MS: mass spectrometry
Mendota_ACZ_1: above-confining-zone monitoring well
Mendota_GW1-4: nested shallow groundwater monitoring wells
Mendota_INJ_1: proposed CO2 injection well
Mendota_OBS_1: injection zone monitoring well
Mendota_USDW_1: USDW monitoring well
MIT: Mechanical integrity test
MVA: monitoring, verification, and accounting
OA: oxygen activation
OES: optical emission spectrometry
SIBH: sigma borehole measurement
SOP: standard operating procedure
SSNA: short-spaced sigma near apparent measurement
TPHI: thermal neutron porosity
UIC: underground injection control
USDW: Underground sources of drinking water
VSP: vertical seismic profile

Disclaimer

Any interpretation, research, analysis, data, results, estimates, or recommendation furnished with the services or otherwise communicated by Schlumberger to Clean Energy Systems at any time in connection with the services are opinions based on inferences from measurements, empirical relationships, and/or assumptions, which inferences, empirical relationships and/or assumptions are not infallible, and with respect to which professionals in the industry may differ. Accordingly, Schlumberger cannot and does not warrant the accuracy, correctness, or completeness of any such interpretation, research, analysis, data, results, estimates, or recommendation. Clean Energy Systems acknowledges that it is accepting the services "as is", that Schlumberger makes no representation or warranty, express or implied, of any kind or description in respect thereto. Specifically, Clean Energy Systems acknowledges that Schlumberger does not warrant that any interpretation, research, analysis, data, results, estimates, or recommendation is fit for a particular purpose, including but not limited to compliance with any government request or regulatory requirement. Clean Energy Systems further acknowledges that such services are delivered with the explicit understanding and agreement that any action taken based on the services received shall be at its own risk and responsibility and no claim shall be made against Schlumberger as a consequence thereof.

To the extent permitted by applicable law, Clean Energy Systems shall not provide this report to any third party in connection with raising finance or procuring investment (other than pursuant to an equity capital raising on a public market) without a No Reliance Letter first being completed and signed by the third party and provided to Schlumberger. The form of the No Reliance Letter being agreed to by both Clean Energy Systems and Schlumberger. Subject to this requirement and upon full payment of applicable fees, copyright ownership in this report shall vest with Clean Energy Systems. Schlumberger grants no title or license or right to Clean Energy Systems to use Schlumberger's Intellectual Property except as necessary for Clean Energy Systems to use the report.

Copyrights

Trademarks

All companies or product names mentioned in this document are used for identification purposes only and may be trademarks of their respective owners. An asterisk (*) denotes a mark of Schlumberger.

2. Overall Strategy and Approach for Testing and Monitoring

The Clean Energy Systems Carbon Capture and Storage (CES-CCS) Project site development and monitoring, verification, and accounting (MVA) program detailed in the Schlumberger Quality Assurance and Surveillance Plan (2021j) will be used to ensure safe underground storage of injected CO_2 and underground sources of drinking water (USDW) non-endangerment.

A preconstruction area of review (AoR) delineation model was constructed using public and purchased data including three 2D seismic lines (from SEI and TGS), well logs, and regional information from public sources (USGS, 2019; DOGGR, 2019) and from IHS Markit. The Second Panoche sandstone is identified as the primary CO_2 sequestration formation with the First Panoche shale layer acting as the primary confinement layer above. Above the Second Panoche are the First Panoche shale and sand and the Moreno formation. The Moreno formation is laterally continuous in the region and identified as the secondary seal. The top of the Moreno formation is about 7,330 ft, and the lowermost USDW is estimated at 1,415 ft. Seismic activity in the area has been very low with no large seismic events within the AoR. A future 3D seismic survey and characterization well will provide site-specific geophysical data to improve the AoR delineation model and help identify any additional risks.

The characterization well will core the Moreno main seal and Panoche sandstones intended for underground storage of CO_2 and will have a comprehensive suite of well logs, fluid sampling, and a core testing program detailed in Attachment G: Construction Details (Schlumberger, 2021g). The characterization well evaluation program is designed to reduce geophysical, geomechanical, and reservoir model uncertainties as well as ensure mechanical integrity of the well.

This CES-CCS project will use the characterization well as the injector (Mendota_INJ_1) and construct three monitoring wells (Figure 1). The locations of these wells are preliminary and expected to be relocated as this project develops:

- Mendota_INJ_1: Characterization well and CO_2 injection well
- Mendota_OBS_1: Monitoring the Panoche injection interval
- Mendota_ACZ_1: The above-confining-zone monitoring well, monitoring the first permeable formation above the Moreno, currently identified as the Garzas formation
- Mendota USDW_1: The monitoring well in the deepest USDW
- Mendota_GW 1-4: Nested shallow groundwater monitoring wells used to monitor the shallow aquifers around the site. The depth of these groundwater monitoring wells will be determined when the groundwater characteristics of the site are better understood. These wells are expected to be shallow in the range of 50 to 500 ft in depth.

The Mendota_OBS_1 Panoche monitoring well will be placed at a distance and direction from the injection well to optimize verification and calibration of the reservoir AoR delineation model and monitor plume migration. The distance and direction of the Panoche monitoring well will be where the reservoir AoR delineation model shows detectable pressure change within 6 months and CO_2 saturation of 10 to 20% within approximately 1 year. The well will be instrumented with continuously monitored pressure and temperature gauges and distributed temperature and acoustic fiber (DAS). Pressure, temperature, and acoustic monitoring will provide early warning of parameters outside of the predicted model and operational limits including microseismic events near the injection site. The Panoche monitoring well will have sampling capability of the Panoche injection sands.

The Mendota_ACZ_1 monitoring well for the first permeable sandstone above the Moreno seal will provide early warning of any leakage past the Moreno seal. The well will be instrumented with continuously monitored pressure and temperature gauges and distributed temperature and acoustic fiber (DAS). Pressure, temperature and acoustic monitoring will provide early warning of leakage of CO_2 past the Moreno seal as well as microseismic events near the injection site. The well will be placed in the updip direction of Moreno formation or in the event a potential fault is identified on the 3D seismic data within the AoR, in the direction of the fault intersection of the Moreno formation.

The Mendota_USDW_1 is a USDW monitoring well and will be placed near the injection well, within 1,000 ft. The lowest formation within the USDW will be verified with formation sampling in the characterization well. The USDW monitoring well will have sampling capability of the USDW.

This testing and monitoring plan and the Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j) will detail the continuous pressure, temperature, and acoustic monitoring of the injection and monitoring wells, and periodic sampling and well logging used to verify safe operation and storage of the injected CO_2. The testing and monitoring plan and the Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j) will provide early warning of any operational or well integrity problems and ensure USDW nonendangerment.

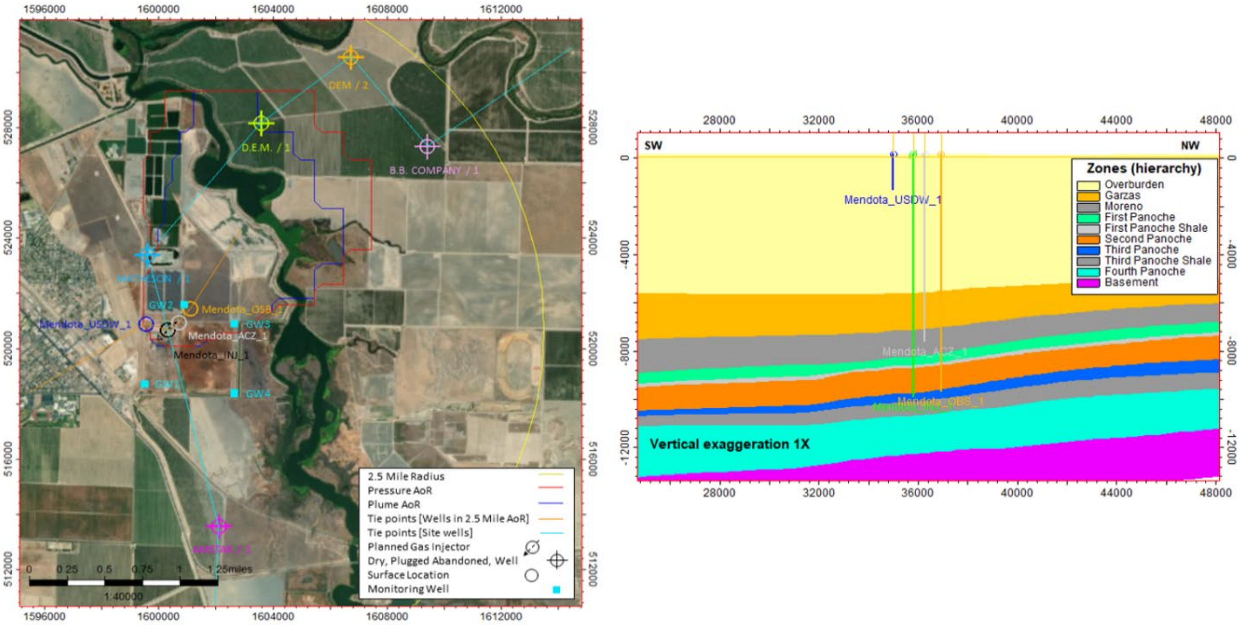


Figure 1. Clean Energy Systems well locations in map view and cross section view.

2.1 Quality Assurance Procedures

The Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j) requires site-specific data that have not been collected in this pre-permitting phase of this project. Once these data are collected in future phases of this project, CES will have the details necessary to develop a comprehensive quality assurance and surveillance plan. A preliminary Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j) has been submitted with this preconstruction Class VI application.

2.2 Reporting Procedures

Clean Energy Systems will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

3. Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

Clean Energy Systems will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

3.1 Sampling Location and Frequency

Sampling will take place quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.

3.2 Analytical Parameters

Clean Energy Systems will analyze the CO_2 for the constituents identified in Table 1 using the methods listed.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)[a]
Oxygen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Argon	ISBT 4.0 (GC/DID) GC/TCD
Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon monoxide	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Oxides of nitrogen	ISBT 7.0 Colorimetric
Ammonia	ISBT 6.0 (DT)
Hydrogen sulfide	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry
[a] An equivalent method may be employed with the prior approval of the UIC Program Director.	

3.3 Sampling Methods

CO_2 stream sampling will occur after the last stage of compression. A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed and sent to the authorized laboratory.

All sample containers will be labeled with durable labels and indelible markings. A unique sample identification number and sampling date will be recorded on the sample containers. Refer to the Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j)for further details.

3.4 Laboratory to be Used and Chain of Custody and Analysis Procedures

Samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The sample chain-of-custody procedures described in the Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j) will be employed.

4. Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

Clean Energy Systems will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long-string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required at 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

4.1 Monitoring Location and Frequency

Clean Energy Systems will perform the activities identified in Table 2 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. The injection well will have pressure/temperature gauges at the surface and in the tubing at the packer. In addition, there will be distributed temperature sensing (DTS) fiber from surface to the tubing packer in the injection well.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Minimum Sampling Frequency[a]	Min. Recording Frequency[b]
Injection pressure		Surface	10 seconds	5 minutes[c]
Injection pressure		Reservoir – proximate to packer	10 seconds	5 minutes[c]
Injection rate		Surface	10 seconds	5 minutes[c]
Injection volume		Surface	10 seconds	5 minutes[c]
Annular pressure		Surface	10 seconds	5 minutes[c]
CO_2 stream temperature		Surface	10 seconds	5 minutes[c]
Temperature		Reservoir – Proximate to packer	10 seconds	5 minutes[c]
Temperature/acoustic	DTS/DAS	Along wellbore to packer	10 seconds	1 hour
Annulus fluid volume		Surface	4 hour	24 hour

[a] Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every 2 seconds and save this value in memory.
[b] Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.
[c] This can be the average of the sampled readings over the period, or maximum or minimum, as appropriate.

4.2 Monitoring Details

Above-ground pressure and temperature instruments shall be calibrated over the full operational range at least annually using American National Standards Institute (ANSI) or other recognized standards. In lieu of removing the injection tubing, downhole gauges will demonstrate accuracy by using a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Pressure transducers shall have a drift stability of less than 1 psi over the operational period of the instrument and an accuracy of ± 5 psi. Sampling rates will be at least once per 5 seconds. Temperature sensors will be accurate to within 1degC.

Flow will be monitored with a mass flowmeter at the compression facility. The flowmeter will be calibrated using accepted standards and be accurate to within ± 0.1%. The flowmeter will be calibrated for the entire expected range of flow rates.

4.2.1 Injection Rate and Pressure Monitoring

Clean Energy Systems will monitor injection operations using the distributive process control system. The surface facility equipment and control system will limit maximum flow and/or limit the wellhead pressure to a pressure that corresponds to the regulatory requirement to not exceed 90% of the injection zone's fracture pressure. All injection operations will be continuously monitored and controlled by the Clean Energy Systems operations staff using the distributive process control system. This system will continuously monitor, control, and record and will alarm and shutdown if specified control parameters exceed their normal operating range.

More specifically, all critical system parameters, e.g., pressure, temperature, and flow rate, will have continuous electronic monitoring with signals transmitted back to a master control system. Clean Energy Systems supervisors and operators will have the capability to monitor the status of the entire system from distributive control centers.

4.2.2 Calculation of Injection Volumes

Flow rate is measured on a mass basis (kg/hr). The downhole pressure and temperature data will be used to perform the injectate density calculation.

The volume of carbon dioxide injected will be calculated from the mass flow rate obtained from the mass flow meter installed on the injection line. The mass flow rate will be divided by density and multiplied by injection time to determine the volume injected.

Density will be calculated using the correlation developed by (Ouyang, 2011). The correlation uses the temperature and pressure data collected to determine the carbon dioxide density. The density correlation is given by

$$\rho = A_0 + A_1 \times P + A_2 \times P^2 + A_3 \times P^3 + A_4 \times P^4$$

where ρ is the density, P is the pressure in psi, and A are coefficients determined by the equations

$$A_i = b_{i0} + b_{i1} \times T + b_{i2} \times T_2 + b_{i3} \times T_3 + b_{i4} \times T_4$$

T is the temperature in degC and the *b* coefficients are presented in Table 3 and Table 4 below.

Table 3. Injection volume calculation b coefficients, pressure < 3000 psi.

	b_{i0}	b_{i1}	b_{i2}	b_{i3}	b_{i4}
i=0	-2.148322085348E+05	1.168116599408E+04	-2.302236659392E+02	1.967428940167E+00	-6.184842764145E-03
i=1	4.757146002428E+02	-2.619250287624E+01	5.215134206837E-01	-4.494511089838E-03	1.423058795982E-05
i=2	-3.713900186613E-01	2.072488876536E-02	-4.169082831078E-04	3.622975674137E-06	-1.155050860329E-08
i=3	1.228907393482E-04	-6.930063746226E-06	1.406317206628E-07	-1.230995287169E-09	3.948417428040E-12
i=4	1.466408011784E-08	8.338008651366E-10	-1.704242447194E-11	1.500878861807E-13	4.838826574173E-16

Table 4. Injection volume calculation b coefficients, pressure >3000 psi.

	b_{i0}	b_{i1}	b_{i2}	b_{i3}	b_{i4}
i=0	6.897382693936E+02	2.730479206931E+00	-2.254102364542E-02	-4.651196146917E-03	3 3.439702234956E-05
i=1	2.213692462613E-01	-6.547268255814E-03	5.982258882656E-05	2.274997412526E-06	-1.888361337660E-08
i=2	-5.118724890479E-05	2.019697017603E-06	-2.311332097185E-08	-4.079557404679E-10	3.893599641874E-12
i=3	5.517971126745E-09	-2.415814703211E-10	3.121603486524E-12	3.171271084870E-14	-3.560785550401E-16
i=4	-2.184152941323E-13	1.010703706059E-14	-1.406620681883E-16	-8.957731136447E-19	1.215810469539E-20

The final volume basis will be calculated as follows:

$$\text{Volume basis } (m^3/hr) = \text{Mass basis } (kg/hr) / \text{density } (kg/m^3)$$

4.2.3 Continuous Monitoring of Annular Pressure

Clean Energy Systems will use the procedures below to monitor annular pressure. The following procedures will be used to limit the potential for any unpermitted fluid movement into or out of the annulus:

1. The annulus between the tubing and the long string of casing will be filled with brine. The brine will have a specific gravity of 1.26 and a density of 9.4 lbm/gal. The hydrostatic gradient is 0.65 psi/ft. The brine will contain a corrosion inhibitor, scaling resistance, oxygen sequestering, and microbial growth inhibition.

2. The surface annulus pressure will be kept at a minimum of 1,142 psi during injection.

3. During periods of well shut down, the surface annulus pressure will be kept at a minimum pressure to maintain a pressure differential of at least 100 psi between the annular fluid directly above (higher pressure) and below (lower pressure) the injection tubing packer.

4. The pressure within the annular space, over the interval above the packer to the confining layer, will be greater than the pressure of the injection zone formation at all times.

5. The pressure in the annular space directly above the packer will be maintained at least 100 psi higher than the adjacent tubing pressure during injection.

The annular monitoring system will consist of a continuous annular pressure gauge, a pressurized annulus fluid reservoir (annulus head tank), pressure regulators, and tank fluid level indication. The annulus system will maintain annulus pressure by controlling the pressure on the annulus head tank using either compressed nitrogen or CO_2.

The annulus pressure will be maintained between approximately 1,100 to 1,200 psi and monitored by the Clean Energy Systems control system gauges. The annulus head tank pressure will be controlled by pressure regulators—one set of regulators to maintain pressure above 1,100 psi by adding compressed nitrogen or CO_2 and the other to relieve pressure above 1,200 psi by venting gas off the annulus head tank.

Any changes to the composition of annular fluid will be reported in the next report submitted to the permitting agency.

If system communication is lost for greater than 30 minutes, project personnel will perform field monitoring of manual gauges every 4 hours or twice per shift for both wellhead surface pressure and annulus pressure and record hard copies of the data until communication is restored.

Average annular pressure and annulus tank fluid level will be recorded daily. The volume of fluid added or removed from the system will be recorded.

4.2.4 Casing-Tubing Pressure Monitoring

Clean Energy Systems will monitor the casing-tubing pressure as presented below.

During the injection timeframe of the project, the casing-tubing pressure will be monitored and recorded in real time. Surface pressure of the casing-tubing annulus is anticipated to be from 1,000 to 1,100 psi. As detailed in the Attachment F: Emergency and Remedial Response Plan (Schlumberger, 2021f), significant changes in the casing-tubing annular pressure attributed to well mechanical integrity will be investigated. Collection and recording of monitoring data will occur at the frequencies described in Table 2.

5. Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), Clean Energy Systems will monitor injection well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

Clean Energy Systems will monitor corrosion using the corrosion coupon method and collect samples according to the description below.

5.1 Monitoring Location and Frequency

Clean Energy Systems corrosion monitoring using the corrosion coupon monitoring will occur quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection. Any break in operations will require an inspection of the coupon within 30 days of commencing operations, and return to the aforementioned schedule of 3, 6, 9, and 12 months.

5.2 Sample Description

Samples of material used in the construction of the compression equipment, pipeline and injection well that may come into contact with the CO_2 stream will be included in the corrosion monitoring program either by using actual material and/or conventional corrosion coupons. The samples consist of those items listed in Table 5. Each coupon will be weighed, measured, and photographed prior to initial exposure (see Section 5.3.2 below).

Table 5. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction[a]
Pipeline	Carbon steel - TBD
Long-String Casing (0-7,332 ft)	Carbon steel T-95 Type 1 per API 05CT
Long-String Casing (7,332ft – 10,412 ft)	Chrome alloy TN 95Cr13 Tenaris Proprietary
Injection Tubing	Chrome alloy L80 13Cr per API 05CT
Wellhead	CO_2 wetted surfaces would be constructed per NACE MR0175/ISO 15156 guidelines. Currently, that is thought is to be a martensitic stainless steel 13Cr but is dependent on final CO_2 stream composition and testing. Wellhead bodies will be a low carbon alloy 4130.
Packer	Chrome alloy CO_2 wetted material Super 13 stainless steel 110-ksi minimum yield strength per UNS S41425/ S41427 standards
[a] As aspects of the project become more defined the CO_2 stream and/or operational parameters material selections may change. Changes will be submitted for approval as they are obtained.	

5.3 Monitoring Details

5.3.1 Sample Exposure

Each sample will be attached to an individual holder and then inserted in a flow-through pipe arrangement. The corrosion monitoring system will be located downstream of all process compression/dehydration/pumping equipment (i.e., at the beginning of the pipeline to the wellhead). To accomplish this, a parallel stream of high-pressure CO_2 will be routed from the pipeline through the corrosion monitoring system and then back into a lower pressure point upstream in the compression system. This loop will operate any time injection is occurring. No other equipment will act on the CO_2 past this point; therefore, this location will provide representative exposure of the samples to the CO_2 composition, temperature, and pressures that will be seen at the wellhead and injection tubing. The holders and location of the system will be included in the pipeline design and will allow for continuation of injection during sample removal.

5.3.2 Sample Handling and Monitoring

The coupons will be handled and assessed for corrosion using the ASTM G1-03 1999 standard for preparing, cleaning, and evaluating corrosion test specimens. The coupons will be photographed, visually inspected with a minimum of 10× power, dimensionally measured (to within 0.0001 in) and weighed (to within 0.0001 gm).

5.3.3 Additional Wellbore Tests

Wireline logs will be used to investigate downhole corrosion to supplement surface measurements. Downhole logging data will be performed prior to commencing injection operations. These logs will provide a baseline casing thickness measurement to which future logs will be compared. These logs can be used to verify reading obtained from surface monitoring equipment. Logging tools will include an ultrasonic imaging tool, magnetic flux leakage, and electromagnetic imaging because these technologies are proven and widely accepted within the industry for their accuracy in determining casing thickness and identifying casing corrosion. Subsequent logs using the same technology will be run at 1-year intervals thereafter. Results will be compared to the initial baseline log. Thickness measurements showing a reduction in thickness greater than twenty percent of API published nominal thickness will warrant further investigation.

6. Above-Confining-Zone Monitoring

Clean Energy Systems will monitor ground water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

Clean Energy Systems will also monitor ground water quality, geochemical changes, and pressure in the first USDWs immediately above the injection zone(s) to meet the requirements of 40 CFR 146.95(f)(3)(i).

The groundwater monitoring plan focuses on the following zones:

- Quaternary: the shallow groundwater (source of local drinking water)
- Santa Margarita or shallow undifferentiated sands: the lowermost USDW
- Garzas formation: first permeable zone above the Moreno shale confining zone.

6.1 Monitoring Location and Frequency

Table 6 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining zone.

Table 6. Monitoring of groundwater quality and geochemical changes above the confining zone during the operation period.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency[a-f]
Groundwater Quality Monitoring				
Quaternary/ shallow strata sources of drinking water	Fluid sampling	Shallow monitoring wells GW_1-4	Four shallow monitoring wells each with one sampling interval	Baseline: Quarterly Year 0-2: Quarterly Year 3-injection end: Annual

Santa Margarita or base of USDW (~1,616 ft MD)	Fluid sampling	Mendota USDW_1	One-point location	Baseline: Quarterly Year 0-2: Quarterly Year 3-injection end: Annual
Well Integrity Monitoring				
Garzas (5804-7332 ft MD)	Fluid sampling	Mendota ACZ_1	1-point location	Baseline: Quarterly Year 0-5: Quarterly Year 6-injection end: Annual
First and Second Panoche (8,437-9,757 ft MD)	Fluid sampling	Mendota_ OBS_1	1-point location	Baseline Year 0-end of injection: Annual
Garzas (5,804-7,332 ft MD)	DAS distributed temperature/ acoustic	Mendota ACZ_1	Distributed measurement	Continuous
First and Second Panoche (8,437-9,757 ft MD)	DAS distributed temperature/ acoustic	Mendota OBS_1	Distributed measurement	Continuous
Garzas (5,804-7,332 ft MD)	Pulsed neutron	Mendota ACZ_1	Survey log	Baseline Year 0-1.5: Quarterly Year 1.5- through injection period: Annual
First and Second Panoche (8,437-9,757 ft MD)	Pulsed neutron	Mendota OBS_1	Survey log	Baseline Year 0-1.5: Quarterly Year 1.5- through injection period: Annual
First and Second Panoche (8,437-9,757 ft MD)	Pulsed neutron	Mendota_ INJ_1	Survey log	Baseline Year 0-1.5: Quarterly Year 1.5- through injection period: Annual

[a] Baseline is prior to CO_2 injection. Baseline sampling and analysis will be completed before injection is authorized.
[b] Year 0 is from initial CO_2 injection.
[c] Quarterly sampling will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.
[d] Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.
[e] Continuous monitoring is described in Table 2 of this plan.
[f] Changes to the ground water monitoring frequency will be with the UIC Program Directors prior approval.

The location of shallow groundwater and above confining zone monitoring wells will be determined in future phases of the project when a more detailed groundwater evaluation is completed. Pulsed neutron is capable of acquiring several different measurements sensitive to CO_2 in the formation and in the casing-formation annulus. Therefore, pulsed neutron can be used to monitor the formation fluids as well as identify mechanical integrity problems that may allow the CO_2 to migrate up the casing annuli.

Figure 2 shows the AoR delineation model for the first 6 months of injection. The Mendota_OBS_1 Panoche monitoring well will be placed at a distance and direction from the injection well to optimize verification and calibration of the reservoir AoR delineation model and monitor plume migration. The distance and direction of the Mendota_OBS_1 will be where the reservoir AoR delineation model shows detectable pressure change within 6 months and/or CO_2 saturation of 10 to 20% within approximately 1 year. The Mendota_ACZ_1 monitoring well for the first permeable sand above the Moreno seal will provide early warning of any leakage past the Moreno seal. The well will be placed in the updip direction of Moreno formation or, in the event a potential fault is identified in the baseline 3D seismic data within the AoR, in the direction of the fault intersection of the Moreno formation.

The baseline 3D seismic data will provide the basis for imaging the initial reservoir conditions prior to injection and should cover an area sufficiently large enough to tie into key calibration wells in the region and primary subregional structure that may affect the migrating injection plume over an extended time period. As the injected CO_2 will change the seismic velocity and amplitude signature, the plume migration can be monitored with the acquisition time lapse or repeat of 3D seismic survey or 3D vertical seismic profile (VSP) acquisition at the later stages of injection. Although it is expected that the seismic signature resulting from injection into these relatively compressible sand shale sequences in the AOR subsurface will be evident, it is recommended to model the prestack seismic signature with simulated fluid injection to determine the degree of sensitivity. Based on the modeling response, the time-lapse seismic monitoring program (3D surface or 3D VSP surveys) can be effectively designed to monitor the plume over time. Furthermore, the area of needed coverage (and method) can be tailored to the anticipated size of the injected plume based upon the injection simulation (shown in the example below).

Pulsed neutron logging is capable of acquiring several different measurements sensitive to CO_2 in the formation and in the casing-formation annulus. Therefore, pulsed neutron logging can be used to monitor the formation fluids as well as to identify mechanical integrity problems that may allow the CO_2 to migrate up the casing annuli.

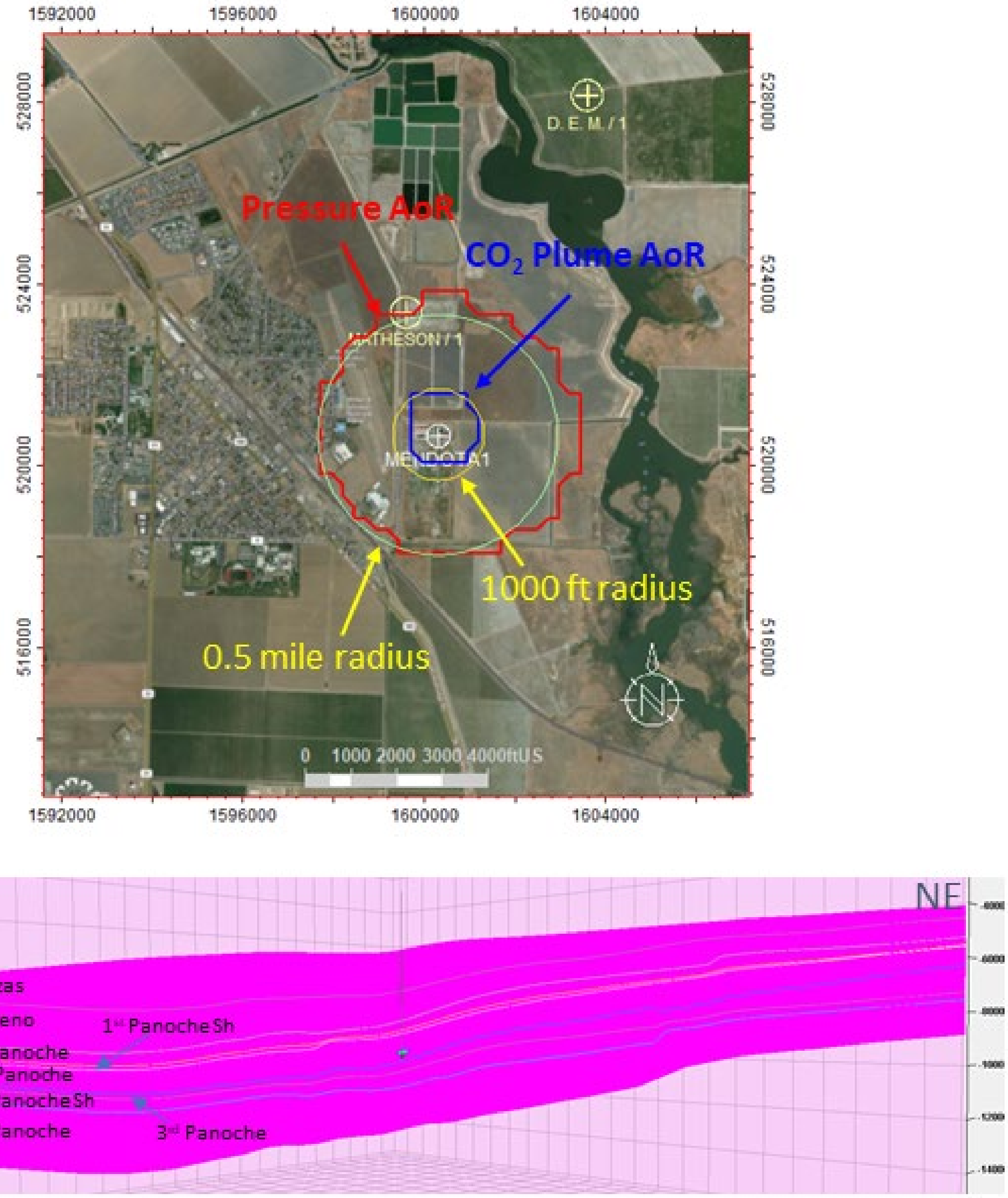


Figure 2. AoR delineation model for 6 months injection in map and cross section view.

6.2 Analytical Parameters

Table 7 identifies the parameters to be monitored and the analytical methods Clean Energy Systems will use. This analytical package is comprehensive enough to meet the site-specific monitoring objectives. If additional methods are required, they will be added during the life of the project.

Table 7. Summary of analytical and field parameters for groundwater samples.

Parameters	Analytical Methods [1]
Quaternary / Shallow strata sources of drinking water	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Zn and Tl	ICP-MS or ICP-OES ASTM D5673, EPA 200.8
Cations: Ca, Fe, K, Mg, Na, and Si	Ion chromatography, EPA Method 200.8 ASTM 6919
Anions: Br, Cl, F, NO_3, and SO_4	Ion chromatography, EPA Method 300.1 ASTM 4327
Dissolved gases: CO_2 , O_2, and H_2S	Coulometric titration ASTM D513-11 EPA 360.1 ASTM D5705
Total dissolved solids	ASTM D5907-10 EPA 160.1
Alkalinity	EPA 310.1
pH (field)	EPA Method 150.1
Specific conductance (field)	EPA 120.1 ASTM 1125
Temperature (field)	Thermocouple
Hardness	ASTM D1126
Turbidity	EPA 180.1
Specific gravity	Modified ASTM 4052
Water density	Modified ASTM 4052
Santa Margarita or base of USDW	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Zn and Tl	ICP-MS or ICP-OES ASTM D5673, EPA 200.8
Cations: Ca, Fe, K, Mg, Na, and Si	Ion chromatography, EPA Method 200.8 ASTM 6919

Parameters	Analytical Methods [1]
Anions: Br, Cl, F, NO_3, and SO_4	Ion chromatography EPA Method 300.1 ASTM 4327
Dissolved gases: CO_2 , O_2, and H_2S	Coulometric titration ASTM D513-11 EPA 360.1 ASTM D5705
Isotopes: $\delta^{13}C$ of dissolved inorganic carbon	Isotope ratio mass spectrometry
Total dissolved solids	ASTM D5907-10 EPA 160.1
Alkalinity	EPA 310.1
pH (field)	EPA Method 150.1
Specific conductance (field)	EPA 120.1 ASTM 1125
Temperature (field)	Thermocouple
Hardness	ASTM D1126
Turbidity	EPA 180.1
Specific gravity	Modified ASTM 4052
Water density	Modified ASTM 4052
Garzas	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Zn and Tl	ICP-MS or ICP-OES ASTM D5673, EPA 200.8
Cations: Ca, Fe, K, Mg, Na, and Si	Ion chromatography, EPA Method 200.8 ASTM 6919
Anions: Br, Cl, F, NO_3, and SO_4	Ion chromatography, EPA Method 300.1 ASTM 4327
Dissolved gases CO_2 , O_2, and H_2S	Coulometric titration, ASTM D513-11 EPA 360.1 ASTM D5705
Isotopes: $\delta^{13}C$ of dissolved inorganic carbon	Isotope ratio mass spectrometry
Total dissolved solids	ASTM D5907-10 EPA 160.1
Alkalinity	EPA 310.1
pH (field)	EPA Method 150.1
Specific conductance (field)	EPA 120.1 ASTM 1125
Temperature (field)	Thermocouple

Parameters	Analytical Methods [1]
Hardness	ASTM D1126
Turbidity	EPA 180.1
Specific gravity	Modified ASTM 4052
Water density	Modified ASTM 4052
[a] ICP, inductively coupled plasma; MS, mass spectrometry; OES, optical emission spectrometry; GC-P, gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director	

6.3 Sampling Methods

Sampling will be performed as described in Section B.2 of the Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j); this describes the groundwater sampling methods to be employed, including sampling standard operating procedures (SOPs) (Section B.2.a/b), and sample preservation (Section B.2.g).

Sample handling and custody will be performed as described in Section B.3 of the Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j).

Quality control will be ensured using the methods described in Section B.5 of the Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j).

6.4 Laboratory to be Used and Chain of Custody Procedures

Samples will be analyzed by a third-party laboratory using standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photo ionization. The sample chain-of-custody procedures described in the Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j) will be employed.

7. External Mechanical Integrity Testing

Clean Energy Systems will conduct at least one of the tests presented in Table 8 periodically during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90.

7.1 Testing Location and Frequency

Mechanical integrity testing (MITs) will be performed annually, up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director

MIT pulsed neutron logging will occur quarterly, by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, 12 months after the date of authorization of injection, 15 months after the date of authorization of injection, 18 months after the date of authorization of injection, and then annually up to 45 days before the anniversary date of authorization of injection each year or will be alternatively scheduled with the prior approval of the UIC Program Director.

7.1.1 Casing Inspection Logs

MIT ultrasonic logs will monitor the presence or absence of corrosion of the injection (Mendota_INJ_1) or monitoring wells (Mendota_OBS_1 and Mendota_ACZ_1) during any workover operation requiring the tubing to be removed, allowing for larger diameter inspection tools and evaluation of the casing behind the well tubing.

Table 8. Mechanical integrity testing (MIT).

Test Description	Location
Temperature log/survey	Along wellbore using DTS or conventional wireline well log
Oxygen activation log	Wireline well log
Pulsed neutron logging	Wireline well log
Acoustic (or noise) log/survey coupled with temperature log/survey	Along wellbore using DAS, DAS equivalent, or conventional wireline well log

7.2 Testing Details

7.2.1 Temperature Logging Using Wireline

To verify the mechanical integrity of the casing of the injection well, temperature data will be recorded across the wellbore from surface down to primary caprock. Bottomhole pressure data near the packer will also be provided. The following procedures will be employed for temperature logging:

The well should be shut-in from injection a minimum of 24 hours prior to logging. This will allow the majority of the well to return to near natural geothermal temperature with the exception of the injection zone.

1. Move in and rig up an electrical logging unit with lubricator.

2. With the well still shut-in, run a temperature survey from the base of the Santa Margarita formation (or higher) to the deepest point reachable in the Panoche at a recommended 30 ft/min.[2]

3. Begin injection at the normal injection rate. Allow injection to stabilize for a recommended 6 hours.

4. Run a temperature survey from the base of the Santa Margarita formation (or higher) to the deepest point reachable in the Panoche while injecting at a rate that allows for safe operations at a recommended 30 ft/min.[1]

5. Stop injection, pull tool back to shallow depth, wait 1 hour.

6. Run a temperature survey over the same interval as step 4.

7. Pull tool back to shallow depth, wait 2 hours.

8. Run a temperature survey over the same interval as step 4.

9. Pull tool back to shallow depth, wait 2 hours.

10. Run a temperature survey over the same interval as step 4.

11. Evaluate data to determine if additional passes are needed for interpretation. Should CO_2 migration be interpreted in the topmost section of the log, additional logging runs over a higher interval will be required to find the top of migration.

12. If additional passes are needed, repeat temperature surveys every 2 hours until 12 hours, over the same interval as step 4.

13. Rig down the logging equipment.

14. Data interpretation involves comparing the time-lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity, i.e., tubing leak or movement of fluid behind the casing. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile.

7.2.2 Temperature Logging Using DTS Fiber Optic Line

Leaks may not be continuous or exhibit abnormal in flow behavior, and therefore conventional temperature logs may not be adequate due to the nature of data collection. Fiber optics offers the ability to continuously and instantaneously monitor the entire length of fiber used in the well and a predetermined sample rate significantly improving the ability to resolve the leak point.

Mendota_INJ_1 will be equipped with a DTS fiber optic temperature monitoring system that is capable of monitoring the injection well's annular temperature along the length of the tubing string instantaneously. The DTS line is used for real time temperature monitoring, and, like a conventional temperature log, can be used for early detection of temperature changes that may

1 Should operational constraints or safety concerns not allow for a logging pass while injecting, an acceptable, the alternate plan is to stop injecting immediately prior to the first logging pass.

indicate a loss of well mechanical integrity. The procedure for using the DTS for well mechanical integrity is as follows:

1. After the well is completed, and prior to injection, a baseline temperature profile will be established. This profile represents the natural temperature gradient for each stratigraphic zone.

   Or, in the case when temporary (wireline) fiber optics is employed:

1(b.) Shut-in from injection a minimum of 24 hours prior to logging. This will allow most of the well to return to near-natural geothermal temperature likely with the exception of the injection zone.

   a. Move in and rig up a fiber optic logging unit with lubricator.

   b. Record a baseline geothermal DTS survey for 1 hour.

   c. Begin injection at the normal injection rate.

2. During injection operation, record the temperature profile for 6 hours prior to shutting in well.

3. Stop injection and record temperature profile for 6 hours.

4. Evaluate data to determine if additional warm back time is needed for interpretation.

5. Data interpretation involves comparing the time-lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity, i.e., tubing leak or movement of fluid behind the casing. The DTS system monitors and records the well's temperature profiles at a preset frequency in real time. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. These data can be continuously monitored to provide real time MIT surveillance making this technology superior to wireline temperature logging.

7.2.3 Oxygen Activation (OA) Logging

To verify the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottomhole pressure data near the packer will also be provided. OA logging will be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Conduct a baseline gamma ray log and casing collar locator log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool.[2]

3. The OA log shall be used only for casing diameters of greater than 1 11/16 in and less than 13 3/8 in.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "no vertical flow behind the casing" section of the well to achieve an accurate, repeatable tool response and for measuring background counts.

6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 ft above the injection interval so that turbulence does not affect the readings.

7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.

8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.

9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.

10. If flow is indicated by the OA log at a location, move uphole or downhole as necessary at no more than 50-ft intervals and take stationary readings to determine the area of fluid migration.

11. Interpret the data: Identification of differences in the activated water's measured gamma ray count-rate profile versus the expected count-rate profile for a static environment. Differences between the measured and expected may indicate flow in the annulus or behind the casing. The flow velocity is determined by measuring the time that the activated water passes a detector.

7.2.4 Pulsed Neutron Logging Using Wireline

To verify the mechanical integrity of the casing of the injection well, temperature data will be recorded across the wellbore from surface down to primary caprock. Bottomhole pressure data near the packer will also be provided. A pre-injection baseline pulsed neutron log should be recorded. The following procedures will be employed for pulsed neutron logging:

---

[2] The gamma ray log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

The well should be in a state of injection for at least 6 hours prior to commencing operations in order to cool injection zones.

1. Move in and rig up an electrical logging unit with lubricator.

2. Run pulsed neutron survey from the Base of the Santa Margarita Formation (or higher) to the deepest point reachable in the Panoche. The Pulsar* pulsed neutron tool should be run in gas-sigma-hydrogen index (GSH) mode.

3. Inspect the Pulsar time-lapse measurements sensitive to the formation, borehole, and annular space compared to pre-injection baseline to evaluate well integrity and detect CO_2 in the annular space or formations outside of the injection zone. Some of the measurements sensitive to the annular space are sigma borehole (SIBH), short-spaced sigma near apparent (SSNA), capture background corrected burst gamma ray count rate (GRAT), fast neutron elastic scattering cross-section (FNXS), and thermal neutron porosity (TPHI). SIBH is the measured sigma or thermal neutron capture cross section of the borehole environment decreasing with the presence of CO_2. SIBH has a correction for the formation sigma, so the raw uncorrected measurement SSNA, which is the primary measurement for SIBH, is also monitored. SSNA may have more sensitivity to annular CO_2 but must be evaluated considering changes in the near-wellbore fluids, i.e., diffusion of fresh fluids present in the near wellbore from the well construction. TPHI is corrected for the borehole environment and is primarily sensitive to the formation. Annular CO_2 may decrease TPHI similar to formation CO_2 but can be masked by borehole corrections. FNXS has a shallow depth of investigation of around 4 in and is sensitive to annular and formation CO_2.

7.2.5 Acoustic (or Noise) Log/Survey Coupled with Temperature Log/Survey

To verify the mechanical integrity of the casing of the injection well, the combination of acoustic, otherwise known as noise, and temperature data will be recorded across the wellbore from surface down to primary caprock. Bottomhole pressure data near the packer will also be provided. The procedures below will be employed for acoustic (noise) and temperature logging.

For conventional tools, it is typical that temperature is logged in the downwards direction followed by a noise log in the upwards direction. Leaks occurring in the annulus of a wellbore will emit a sound as the fluids/gases flow to surface. Running an acoustic (noise) survey in addition to a temperature log can provide significant information about the nature of the leak and determine when multiple leak points are occurring. It is recommended that this combination or a form thereof is run in most survey applications.

The well should be shut-in from injection a minimum of 24 hours prior to logging. This will allow the majority of the well to return to near-natural geothermal temperature with the exception of the injection zone.

1. Move in and rig up an electrical logging unit with lubricator.

2. With the well still shut-in, run a temperature survey from the Base of the Santa Margarita Formation (or higher) to the deepest point reachable in the Panoche at a recommended 30 ft/min.[3]

3. Perform station stop noise logs at regular intervals, proceed to the next station stop in the upwards direction or in the case of a continuous capable noise tool, log in the upwards direction to establish the baseline.

4. Begin injection at the normal injection rate. Allow injection to stabilize for a recommended 6 hours.

5. Log down with the temperature tool while injecting at a stable rate at a recommended logging speed of 30 ft/min.

6. A noise survey at this point will be dominated by the noise of injection and is not required.

7. Stop injection, pull tool back to shallow depth, wait 1 hour.

8. Run a temperature survey over the same interval as step 2.

9. Perform station stop noise logs at regular intervals, proceed to the next station stop in the upwards direction or in the case of a continuous capable noise tool, log in the upwards direction to establish the baseline.

10. Pull tool back to shallow depth, wait 2 hours.

11. Run a temperature survey over the same interval as step 2, at a recommended logging speed of 30 ft/min.

12. Perform station stop noise logs at regular intervals, proceed to the next station stop in the upwards direction or in the case of a continuous capable noise tool, log in the upwards direction to establish the baseline.

13. Pull tool back to shallow depth, wait 2 hours.

14. Run a temperature survey over the same interval as step 2, at a recommended logging speed of 30 ft/min.

15. Perform station stop noise logs at regular intervals, proceed to the next station stop in the upwards direction or in the case of a continuous capable noise tool, log in the upwards direction to establish the baseline.

[3] Should operational constraints or safety concerns not allow for a logging pass while injecting, an acceptable, alternate plan is to stop injecting immediately prior to the first logging pass.

16. Evaluate data to determine if additional passes are needed for interpretation. Should CO_2 migration be interpreted in the topmost section of the log, additional logging runs over a higher interval will be required to find the top of migration.

17. If additional passes are needed, repeat temperature surveys every 2 hours until 12 hours, over the same interval as step 2.

18. Rig down the logging equipment.

19. Data interpretation involves comparing the time-lapse well temperature profiles and looking for temperature anomalies that may indicate a failure of well integrity, i.e., tubing leak or movement of fluid behind the casing. As the well cools down the temperature profile along the length of the tubing string is compared to the baseline. Any unplanned fluid movement into the annulus or outside the casing creates a temperature anomaly when compared to the baseline cooling profile. Similarly, an acoustic signature will exist in the event of a leak. The frequency at which the leak will flow depends on if the CO_2 is flowing as a gas, a liquid, or a combination thereof. The survey should be acquired with both low and high frequency ranges simultaneously.

7.2.6 Acoustic and Temperature Logging Using Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS) or Equivalent Fiber Optic Line

Leaks may not be continuous or exhibit abnormal flow behavior and therefore conventional temperature logs may not be adequate due to the nature of data collection. Fiber optics offers the ability to continuously and instantaneously monitor the entire length of fiber used in the well and a predetermined sample rate significantly improving the ability to resolve the leak point. A combination of DAS and DTS fiber optics is capable of monitoring the injection well's annular temperature and acoustic signature simultaneously and instantaneously along the length of the tubing or casing string. The DAS/DTS line is used for real time acoustic and temperature monitoring and, like a conventional temperature log, can be used for early detection of temperature changes that may indicate a loss of well mechanical integrity. The procedure for using the DAS/DTS for well mechanical integrity is as follows:

1. After the well is completed and prior to injection, a baseline acoustic and temperature profile will be established. This profile represents the natural temperature gradient for each stratigraphic zone and the natural acoustic state of the wellbore.

   Or, in the case when temporary (wireline) fiber optics is employed:

1(b.) Shut-in from injection a minimum of 24 hours prior to logging. This will allow most of the well to return to near natural geothermal temperature likely with the exception of the injection zone and reset to a background acoustic level.

   a. Move in and rig up a fiber optic logging unit with lubricator.

   b. Record a background DAS and baseline geothermal DTS survey for 1 hour.

   c. Begin injection at the normal injection rate.

2. During injection operation, record the acoustic-temperature profile for 6 hours prior to shutting in well.

3. Stop injection and record acoustic-temperature profile for 6 hours.

4. Evaluate data to determine if additional warm-back time is needed for interpretation.

5. There is not a requirement to move fiber optics upwards or downwards in the well to collect data as the cable itself is the measuring device. Requirements are to deploy on bottom of the well or on the bottom logged interval. Data interpretation involves comparing the time-lapse well acoustic and temperature profiles and looking for acoustic-temperature anomalies that may indicate a failure of well integrity, i.e., tubing leak or movement of fluid behind the casing. The DAS/DTS system monitors and records the well's temperature profiles at a preset frequency in real time. As the well cools down, the temperature profile along the length of the tubing string is compared to the baseline. Similarly, an acoustic signature will exist in the event of a leak. The frequency at which the leak will flow depends on if the CO_2 is flowing as a gas, a liquid, or a combination thereof. The survey should be acquired with both low- and high-frequency ranges simultaneously. Any unplanned fluid movement into the annulus or outside the casing creates an acoustic and temperature anomaly when compared to the baseline profiles. This data can be continuously monitored to provide real-time MIT surveillance making this technology superior to wireline temperature logging.

8. Pressure Falloff Test Procedures

8.1 Purpose

The purpose of this test is to identify injection interval or wellbore problems and injection interval characteristics. It is the responsibility of the permittee to develop a testing procedure which will generate adequate data for a meaningful analysis.

8.2 Regulatory Citation

The Class VI Rule requires monitoring of the pressure buildup in the injection zone at least every five (5) years and more frequently if required by the UIC program director [40 CFR 146.90(f), including at a minimum, shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff. This test is known as the formation pressure falloff test.

8.3 Timing of Falloff Tests and Report Submission

Falloff tests must be conducted within one year from the date of approval and at least every 5 years thereafter. The falloff testing report should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the applicable condition and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

8.4 Falloff Test Report Requirements

In general, the report to EPA should provide general information and an overview of the falloff test, an analysis of the pressure data obtained during the test, a summary of the test results, and a comparison of the results with the parameters used in the no migration demonstration. Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each report. The falloff test report should include the following information:

1. Company name and address.
2. Test well name and location.
3. The name and phone number of the facility contact person. The contractor contact may be included if approved by the facility in addition to a facility contact person.
4. A photocopy of an openhole log (SP or gamma ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. Well schematic showing the current wellbore configuration and completion information:
    - Wellbore radius
    - Completed interval depths
    - Type of completion (perforated, screen and gravel packed, openhole)
6. Depth of fill depth and date tagged.
7. Offset well information:
    - Distance between the test well and offset well(s) completed in the same interval or involved in an interference test.
    - Simple illustration of locations of the injection and offset wells.
8. Chronological listing of daily testing activities.
9. Electronic submission of the raw data (time, pressure, and temperature) from all pressure gauges will be provided in a digital format. A READ.ME file will list all files included and any necessary explanations of the data. A separate file containing any edited data used in the analysis can be submitted as an additional file.
10. Tabular summary of the injection rate or rates preceding the falloff test. At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs. time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
11. Rate information from any offset wells completed in the same interval. At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs. time plot is also helpful to illustrate the rate changes.
12. Hard copy of the time and pressure data analyzed in the report.
13. Pressure gauge information:

- List all the gauges utilized to test the well
- Depth of each gauge
- Manufacturer and type of gauge. Include the full range of the gauge.
- Resolution and accuracy of the gauge as a percentage of full range.
- Calibration certificate and manufacturer's recommended frequency of calibration

14. General test information:
    - Date of the test
    - Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well and any offset wells.
    - Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
15. Reservoir parameters (determination):
    - Formation fluid viscosity, μ_f, cP (direct measurement or correlation)
    - Porosity, φ fraction (well log correlation or core data)
    - Total compressibility, c_t psi^{-1} (correlations, core measurement, or well test)
    - Formation volume factor, rvb/stb (correlations, usually assumed 1 for water)
    - Initial formation reservoir pressure
    - Date reservoir pressure was last stabilized (injection history)
    - Justified interval thickness, h ft
16. Waste plume:
    - Cumulative injection volume into the completed interval
    - Calculated radial distance to the waste front
    - Average historical waste fluid viscosity, if used in the analysis
17. Injection period:
    - Time of injection period
    - Type of test fluid
    - Type of pump used for the test (e.g., plant or pump truck)
    - Type of rate meter used
    - Final injection pressure and temperature
18. Falloff period:
    - Total shut-in time, expressed in real time and elapsed time
    - Final shut-in pressure and temperature
    - Time well went on vacuum, if applicable
19. Pressure gradient:
    - Gradient stops - for depth correction
20. Calculated test data: include all equations used and the parameter values assigned for each variable within the report
    - Radius of investigation
    - Slope or slopes from the semilog plot
    - Transmissibility
    - Permeability
    - Calculation of skin
    - Calculation of skin pressure drop

- Discussion and justification of any reservoir or outer boundary models used to simulate the test
- Explanation for any pressure or temperature anomaly if observed

21. Graphs:
    - Cartesian plot: pressure and temperature vs. time
    - Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
    - Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
    - Injection rate(s) vs. time: test well and offset wells (not a circular or strip chart)
22. A comparison of all parameters with those used in the demonstration, including references where the parameters can be found.
23. A copy of the latest radioactive tracer run to fulfill the mechanical integrity testing requirement for the State and a brief discussion of the results.
24. Compliance with any unusual approval conditions such as the submission of a flow profile survey. These additional conditions may be addressed either in the falloff testing report or in an accompanying document.

8.5 Planning

The radial flow portion of the test is the basis for all pressure transient calculations. Therefore, the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

Successful well testing involves the consideration of many factors, most of which are within the operator's control. Some considerations in the planning of a test include:

- Adequate storage for the waste should be ensured for the duration of the test.
- Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test.
- Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge.
- The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period.
- The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well.
- Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.

- Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- Other pressure transient tests may be used in conjunction or in place of a falloff test in some situations. For example, if surface pressure measurements must be used because of a corrosive waste stream and the well will go on vacuum following shut-in, a multi-rate test may be used so that a positive surface pressure is maintained at the well. However, other pressure transient tests will be subject to EPA approval prior to the application.
- If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

8.6 Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
    - Review previous well tests, if available
    - Simulate the test using measured or estimated reservoir and well completion parameters
    - Calculate the time to the beginning of radial flow using the empirically-based equations provided in EPA Region 9 falloff testing guideline (https://archive.epa.gov/region9/water/archive/web/pdf/falloff-testing-guidlines.pdf). The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period.
    - Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well-developed semi log straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.
2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The properties of the fluid should be consistent. Any mobility issues should be identified and addressed in the analysis if necessary.
3. Bottomhole pressure measurements are required.
4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type.

8.7 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well
2. Simplify the pressure transients in the reservoir

- Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
- Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
- Do not shut-in two wells simultaneously or change the rate in an offset well during the test.

3. The well must be shut-in at the wellhead or as near to the wellhead as feasible in order to minimize wellbore storage and after flow. The shut-in must be accomplished as instantaneously as possible to prevent erratic pressure behavior during the test.
4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.
5. Measure and record the properties of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.
6. The surface readout downhole pressure gauge must be located at or near the top of the injection interval, unless previous testing indicates a more appropriate location. A surface readout should be provided to allow flexibility in determining appropriate pressure measuring and recording time intervals and to ensure valid test data is generated and false testing runs can be identified and aborted.
7. The injection rate and injection liquid density for the test must be held constant prior to shut-in.
8. The injection rate must be high enough and continuous for a period of time sufficient to produce a pressure buildup that will result in valid test data.
9. The injection rate must result in a pressure buildup such that a semi log straight line can be determined from the Horner plot. The injection rate should be the maximum injection rate that can be feasibly maintained constant in order to maximize pressure changes in the formation and provide valid test results, but the injection pressure will not exceed the maximum allowable surface injection pressure specified in the permit.
10. If the stabilization injection period is interrupted, for any reason and for any length of time, the stabilization injection period must be restarted.
11. The falloff portion of the test must be conducted for a length of time sufficient such that the pressure is no longer influenced by wellbore storage or skin effects and enough data points lie within the infinite acting period and the semi log straight line is well developed.

8.8 Evaluation of the Test Results

A licensed geologist or licensed professional engineer, licensed by the Board for Professional Engineers, Land Surveyors, and Geologists to practice geology or engineering in California and knowledgeable in the methods of pressure transient test analysis, must evaluate the test results.

1. The following information and evaluations must be provided with the test report:
    - Prepare a Cartesian plot of the pressure and temperature versus real time or elapsed time.
    - Confirm pressure stabilization prior to shut-in of the test well

2. Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution
3. Prepare a log-log diagnostic plot of the pressure and semi log derivative. Identify the flow
    - Regimes present in the well test
    - Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff
    - Mark the various flow regimes - particularly the radial flow period
    - Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
    - If there is no radial flow period, attempt to type curve match the data
4. Prepare a semi log plot.
    - Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
    - Draw the semi log straight line through the radial flow portion of the plot and obtain the slope of the line
    - Calculate the transmissibility
    - Calculate the skin factor and skin pressure drop
    - Calculate the radius of investigation
5. Explain any anomalous data responses. The analyst should investigate physical causes other than reservoir responses.
6. All equations used in the analysis must be provided with the appropriate parameters substituted in them.

Note: Tests conducted in relatively transmissive reservoirs are more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. For this reason, the plot of the temperature data should be reviewed. Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.

9. Carbon Dioxide Plume and Pressure Front Tracking

CES will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

9.1 Plume Monitoring Location and Frequency

Table 9 presents the methods that CES will use to monitor the migration of the CO_2 plume, including the activities, locations, and frequencies CES will employ. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 10.

9.2 Plume Monitoring Details

CES will conduct fluid sampling and analysis to detect changes in groundwater to directly monitor the carbon dioxide plume. The parameters to be analyzed as part of fluid sampling in the Panoche sand (i.e., the injection zone) and analytical methods are presented in Table 10.

Indirect plume monitoring will be employed using pulsed neutron capture logs to monitor CO_2 saturation. Time-lapse surface 3D seismic or vertical seismic profiles (borehole VSPs) in the monitoring wells will also be used to image the developing CO_2 plume for indirect plume monitoring. The baseline 3D seismic survey will cover a large enough area to encompass calibration wells and potential migration pathways plus offset features such as subregional faulting. The current design for the baseline 3D seismic survey has a 41.25 ft by 82.5 ft bin size, and will cover the plume extent plus a 1/2-mile full fold buffer. The subsequent time-lapse seismic monitoring (3D surface survey or 3D VSP, with the method to be determined after collection of the baseline survey) can be constrained to an "image area" (with 3D migration processing) with sufficient coverage to define the growing plume. The baseline and subsequent time-lapse surveys will be processed using a 4D technique which is sensitive to differences between surveys. These differences will be mapped to show the change in plume extent over time.

Table 9. Plume monitoring activities during the operation period.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency[a–d]
Direct Plume Monitoring				
Panoche	Fluid sampling	Mendota_OBS_1	1-point location, 1 interval: -9,300 ~ -9,600 ft MSL	Annual
Indirect Plume Monitoring				
Panoche	Pulsed neutron logging	Mendota_INJ_1	Survey log	Year 0-2 Quarterly; Year 2+ Annual
		Mendota_OBS_1	Survey log	Year 0-2 Quarterly; Year 2+ Annual
Multiple	Spinner survey	Mendota_INJ_1	Survey and multiple station logs	Year 0-2 Quarterly; Year 2+ Annual
Multiple	Time-lapse VSP survey	Mendota_OBS_1	Monitor 3D VSP survey image area ~ 100 to 2,000 acres	Baseline, Year 2, 3, 4
Multiple	3D surface seismic survey, or combination surface and well VSP	Full coverage focusing on the northern extent of plume area	Fold image coverage: Baseline ~ 15 square miles. Monitor 3D survey image area ~ 2,000+ acres	Baseline, Year 3

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency[a–d]
Multiple	Passive seismic	A combination of borehole (DAS) and surface seismic stations	The passive seismic monitoring system has the ability to detect seismic events over M1.0 within the AoR.	Continuous

[a] Baseline monitoring will be completed before injection is authorized.
b Annual monitoring will be performed up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.
c Logging surveys will take place up to 45 days before the anniversary date of authorization of injection each year or alternatively scheduled with the prior approval of the UIC Program Director.
d Seismic surveys will be performed in the 4th quarter before or the 1st quarter of the calendar year shown or alternatively scheduled with the prior approval of the UIC Program Director.

Table 10. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods [a]
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, and Tl	ICP-MS or ICP-OES ASTM D5673, EPA 200.8
Cations: Ca, Fe, K, Mg, Na, and Si	Ion Chromatography, EPA Method 200.8 ASTM 6919
Anions: Br, Cl, F, NO_3, and SO_4	Ion chromatography EPA Method 300.1 ASTM 4327
Dissolved gases: CO_2, O_2, and H_2S	Coulometric titration, ASTM D513-11 EPA 360.1 ASTM D5705
Isotopes: $\delta^{13}C$ of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	ASTM D5907-10 EPA 160.1
Water Density (field)	Modified ASTM 4052
Alkalinity	EPA 310.1
pH (field)	EPA Method 150.1
Specific conductance (field)	Modified ASTM 4052
Resistivity	ASTM D1125-14
Turbidity	EPA 180.1
Total hardness	ASTM D1126
Temperature (field)	Thermocouple

[a] ICP, inductively coupled plasma; MS, mass spectrometry; OES, optical emission spectrometry. An equivalent method may be employed with the prior approval of the UIC Program Director.

Figure 3 shows the predicted CO_2 plume and pressure front (ΔPc=3.5 psi) after 6 months of injection. To capture the CO_2 plume migration within this timeframe, appropriate monitoring locations relative to the CO_2 plume and pressure front would be approximately 1,000 ft to the north and northeast from the injection well. Figure 4–Figure 7 show the temporal evolution of CO_2 plume and pressure front at 5, 20, 30, and 70 years after the commencement of CO_2 injection.

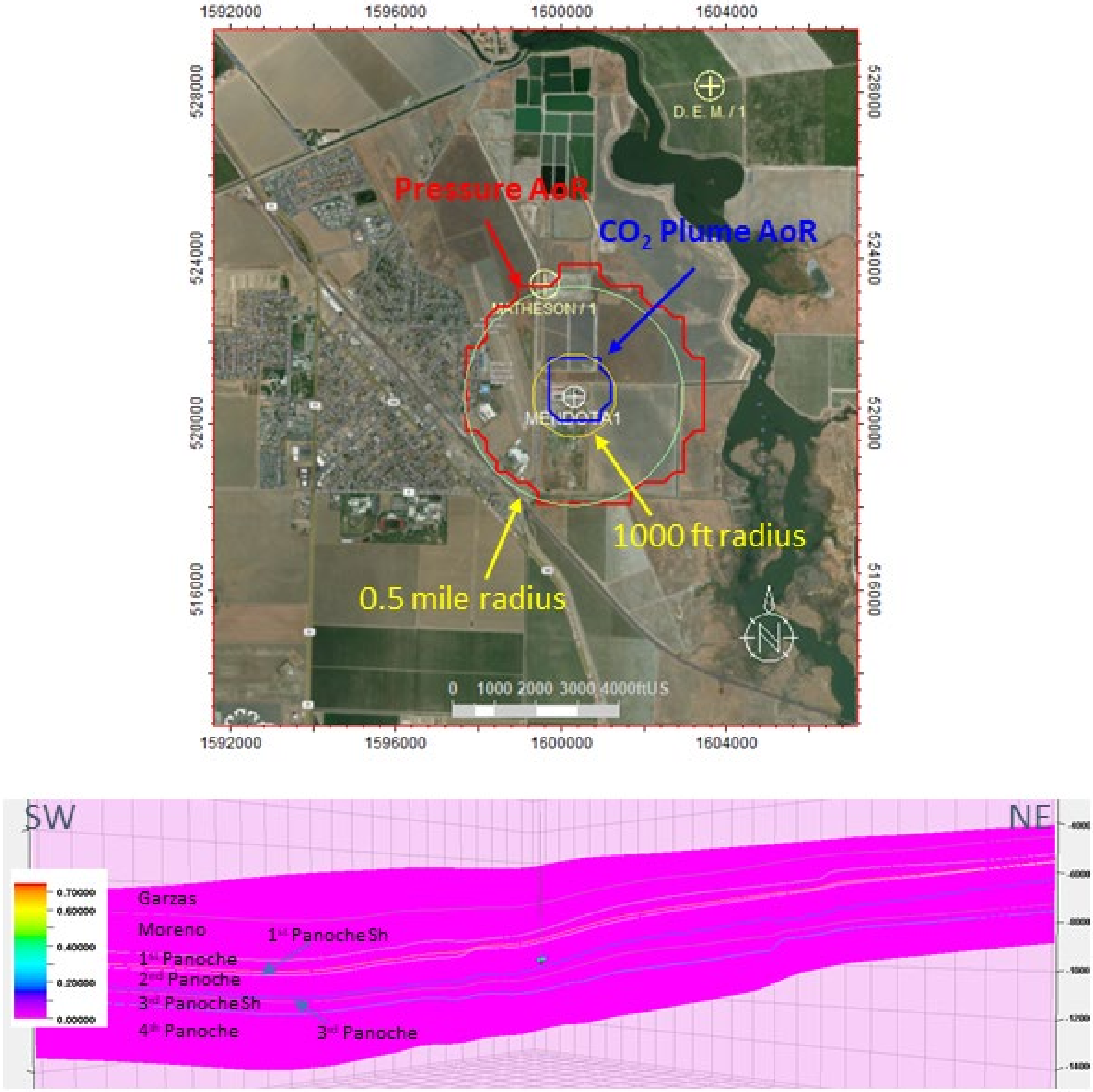
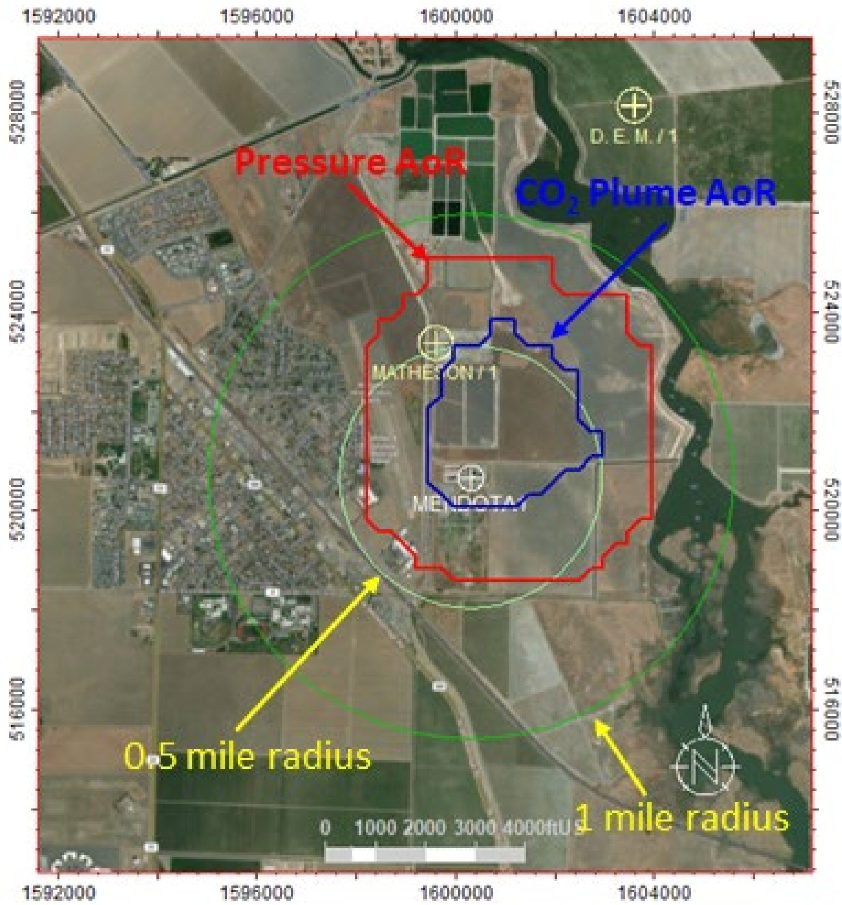


Figure 3. Predicted extent of the CO_2 plume and pressure front ($\Delta Pc = 3.5$ psi) after 6 months of injection.



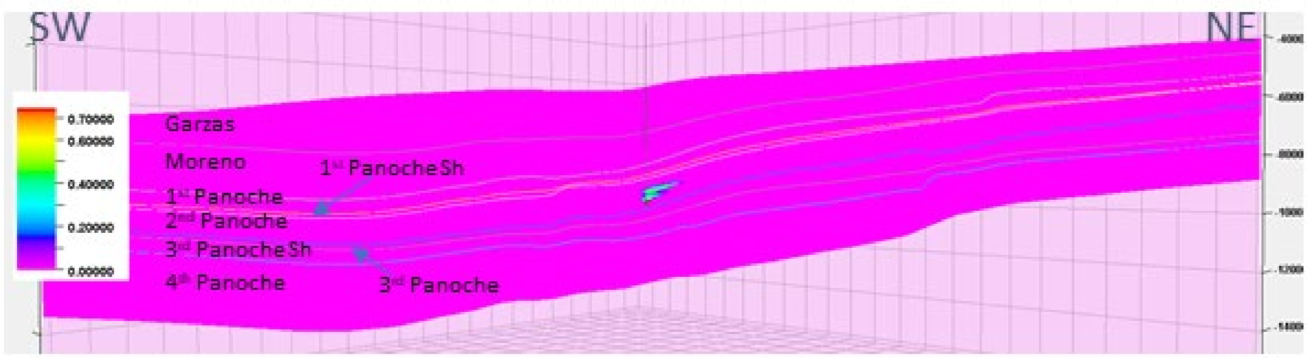


Figure 4. Predicted extent of the CO_2 plume and pressure front ($\Delta Pc = 3.5$ psi) after 5 years of injection.

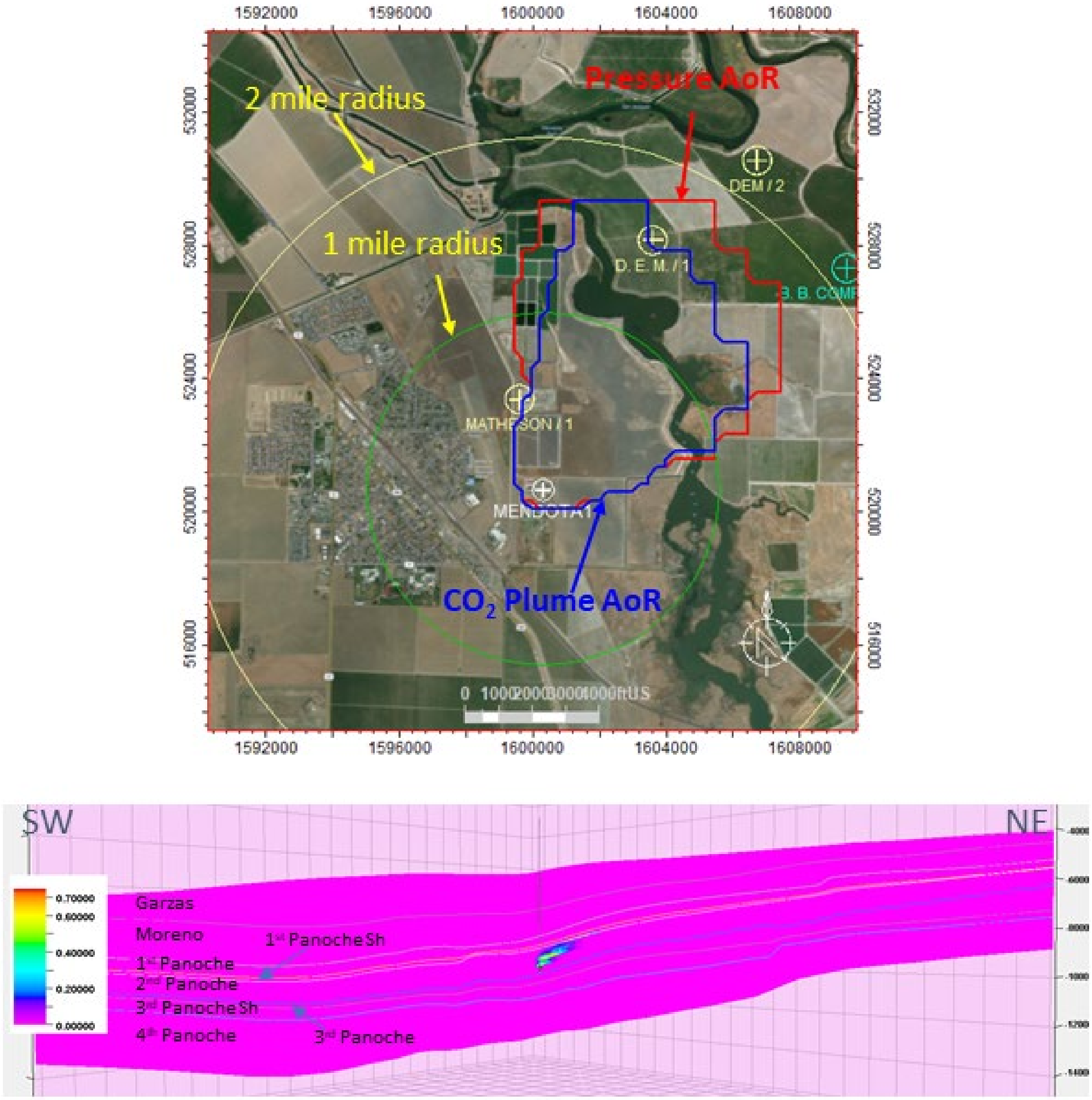


Figure 5. Predicted extent of the CO_2 plume and pressure front ($\Delta Pc = 3.5$ psi) after 20 years of injection.

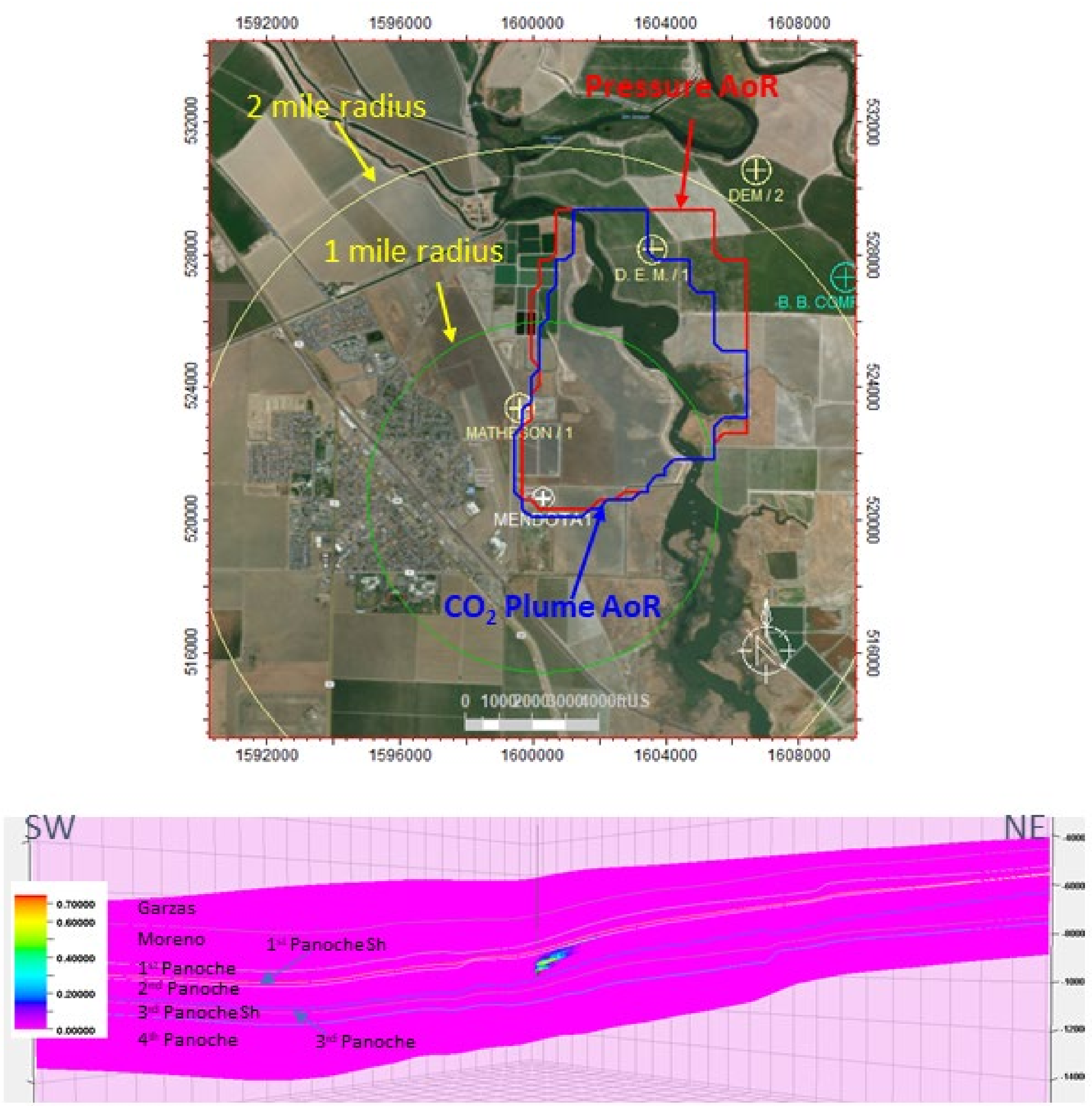


Figure 6. Predicted extent of the CO_2 plume and pressure front ($\Delta Pc = 3.5$ psi) after 10 years of post-injection.

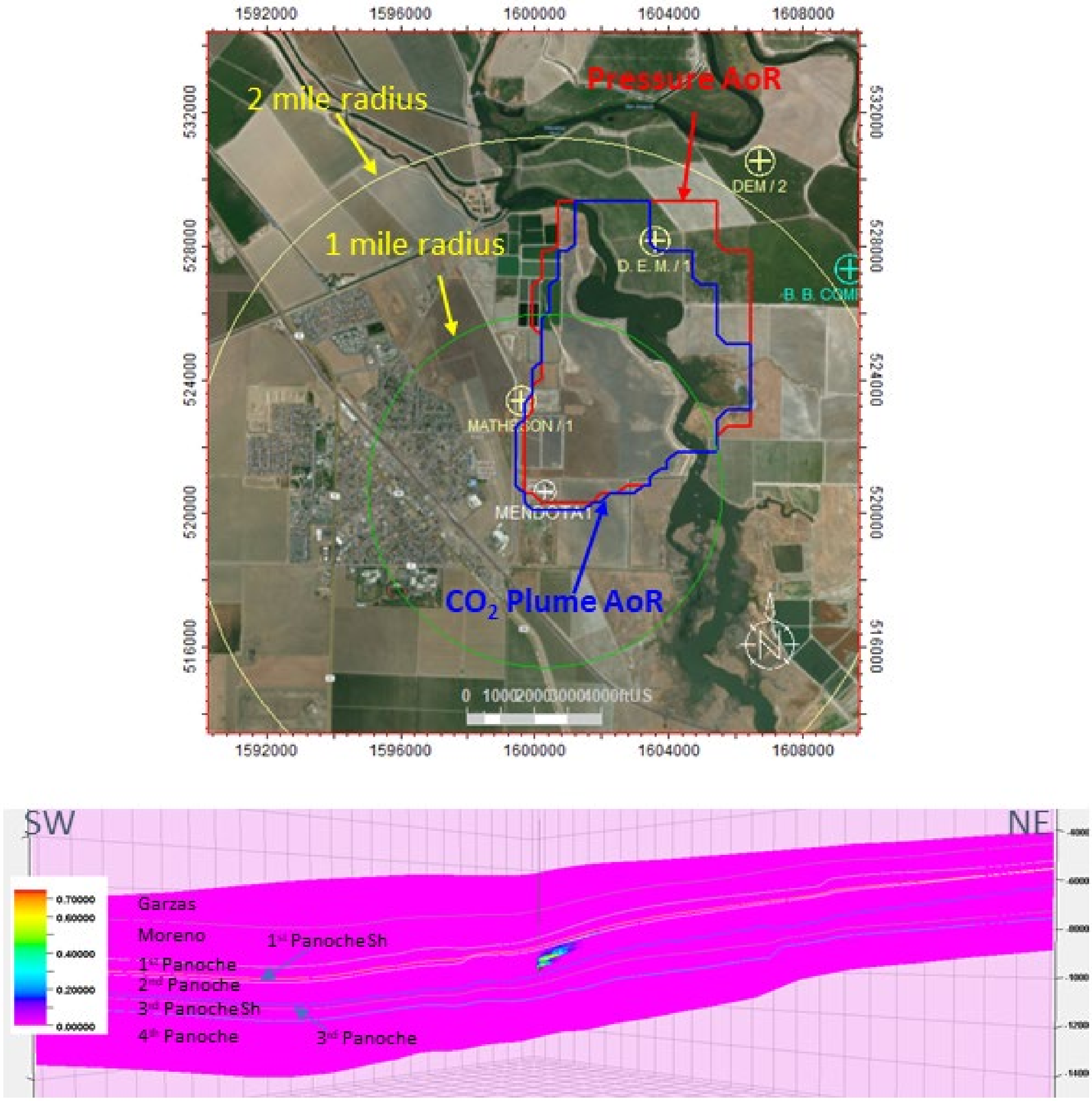


Figure 7. Predicted extent of the CO_2 plume and pressure front ($\Delta Pc = 3.5$ psi) after 50 years of post-injection.

9.3 Pressure-Front Monitoring Location and Frequency

Table 11 presents the methods that CES will use to monitor the position of the pressure front, including the activities, locations, and frequencies CES will employ. The Schlumberger Quality Assurance and Surveillance Plan (Schlumberger, 2021j) requires site-specific data that have not been collected in this pre-permitting phase of this project. Once these data are collected in future phases of this project, CES will have the details necessary to develop a comprehensive quality assurance and surveillance plan.

9.4 Pressure-Front Monitoring Details

CES will deploy pressure/temperature monitors and DTS to directly monitor the position of the pressure front. Table 11 shows the pressure-front monitoring activities. Passive seismic monitoring combination of borehole and surface seismic stations to detect local events over M 1.0 within the AoR will also be performed. The predicted bottomhole pressure profiles at the proposed injection well are shown in Figure 8.

Table 11. Pressure-front monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Pressure-Front Monitoring				
Panoche formation (First, Second, and Third Panoche sands)	Pressure/ temperature monitoring	Mendota_OBS_1	1 point location, 3 intervals: (~ -8,600, -9,400, -10,000 ft MSL)	Continuous
Panoche injection interval	Pressure/ temperature monitoring	Mendota_INJ_1	1 point location, 1 interval: PT @ Perfs (~ -9400-9620 ft MSL)	Continuous
Garzas (USDW above confining zone)	Pressure/ temperature monitoring	Mendota_ACZ_1	1 point location, 1 interval: PT @ Perfs (~ -7,250 ft MSL)	Continuous
Multiple	DTS	Mendota_OBS_1	1-point location, distributed measurement to -9000 ft MSL.	Continuous
		Mendota_INJ_1	1-point location, distributed measurement to 9400 ft KB/-9200 ft MSL	Continuous
Other Plume/Pressure-Front Monitoring				
Multiple	Passive seismic	A combination of borehole and surface seismic stations	The passive seismic monitoring system has the ability to detect seismic events over M1.0 within the AoR.	Continuous

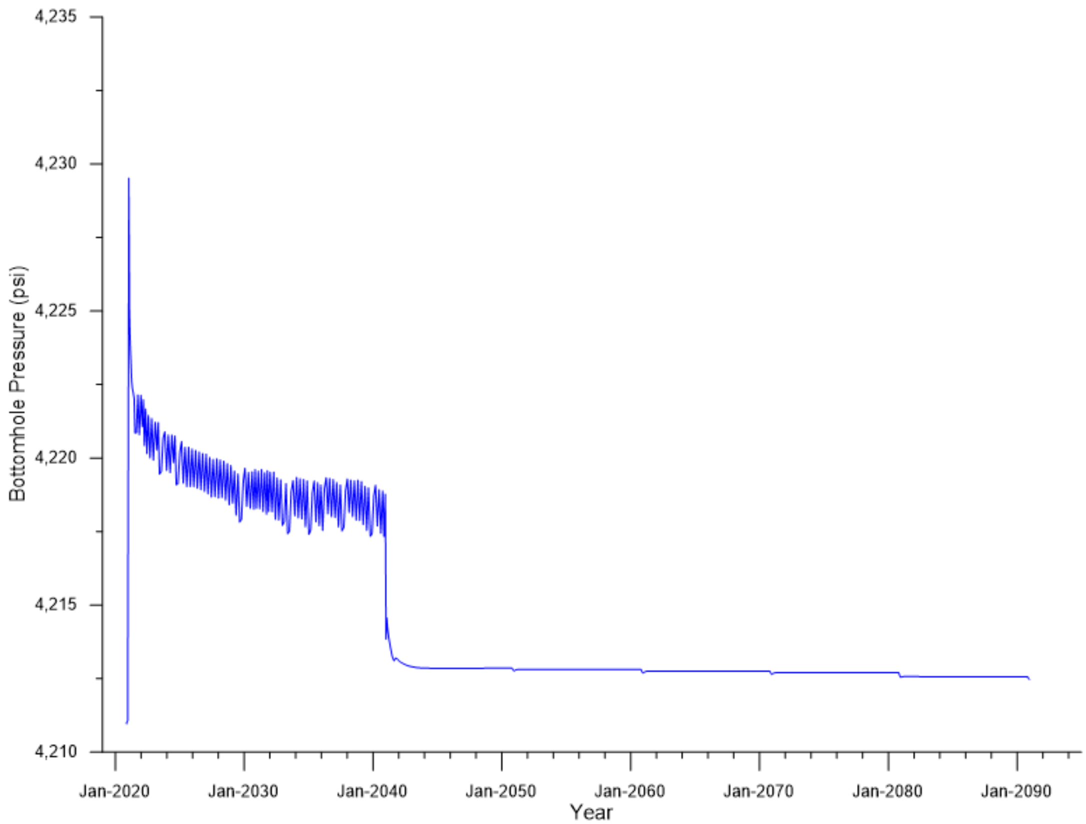


Figure 8. Predicted bottomhole pressure profile at the middle of the injection interval, simulated for 70 years after the commencement of injection (20-year injection and 50-year post-injection).

10.References

DOGGR. (2019). Retrieved from Division of Oil, Gas, and Geothermal Resources: https://www.conservation.ca.gov/dog

Ouyang, L. (2011). New Correlations for Predicting the Density and Viscosity of Supercritical Carbon Dioxide Under Conditions Expected in Carbon Capture and Sequestration Operations. *The Open Petroleum Engineering Journal, 5*(1), 13-21. doi:https://doi.org/10.2174/1874834101104010013

Schlumberger. (2021a). *Attachment A: Summary of Requirements Class VI Operating and Reporting Conditions.*

Schlumberger. (2021b). *Attachment B: Area of Review and Corrective Action Plan 40 CFR 146.84(b) Clean Energy Systems Mendota.*

Schlumberger. (2021c). *Attachment C: Testing and Monitoring Plan 40 CFR 146.90 Clean Energy Systems Mendota.*

Schlumberger. (2021d). *Attachment D: Injection Well Plugging Plan 40 CFR 146.92(B) Clean Energy Systems Mendota.*

Schlumberger. (2021e). *Attachment E: Post-Injection Site Care and Site Closure Plan 40 CFR 146.93(A) Clean Energy Systems Mendota.*

Schlumberger. (2021f). *Attachment F: Emergency and Remedial Response Plan 40 CFR 146.94(A) Clean energy Systems Mendota.*

Schlumberger. (2021g). *Attachment G: Construction Details Clean Energy Systems Mendota.*

Schlumberger. (2021h). *Attachment H: Financial Assurance Demonstration 40 CFR 146.85 Clean Energy Systems Mendota.*

Schlumberger. (2021i). *Class VI Permit Application Narrative 40 CFR 146.82(A) Clean Energy Systems Mendota.*

Schlumberger. (2021j). *Schlumberger Quality Assurance and Surveillance Plan.*

USGS. (2019). *U.S. Quarternary Faults*. Retrieved from USGS Geologic Hazard Science Center: https://usgs.maps.arcgis.com/apps/webappviewer/index.html?id=5a6038b3a1684561a9b0aadf88412fcf